1. PURPOSE AND NEED FOR AGENCY ACTION

1.1 INTRODUCTION

This environmental assessment (EA) has been prepared by the U.S. Department of Energy (DOE), in compliance with the National Environmental Policy Act of 1969 (NEPA) as amended (42 USC 4321 et seq.), to evaluate the potential environmental impacts associated with constructing and operating an integrated multi-pollutant control system proposed by CONSOL Energy Inc. and AES Greenidge LLC. The EA will be used by DOE in making a decision on whether or not to provide cost-shared funding to design, construct, and demonstrate the proposed system at the existing 107-MW Unit 4 of Applied Energy Services' (AES's) Greenidge Station in Dresden, New York. DOE's share of the funding for the 4.5-year demonstration project is expected to be about $14.5 million, while about $18.3 million would be provided by CONSOL and its project partners. The project has been selected by DOE under the Power Plant Improvement Initiative (PPII) to demonstrate the integration of technologies to reduce emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_x), sulfur trioxide (SO_3), mercury (Hg), hydrogen chloride (HCl), and hydrogen fluoride (HF) from smaller (<300 MW) coal-fired boilers.

The U.S. Congress established the PPII in Pub. L. 106-291, Department of the Interior and Related Agencies Appropriations Act for Fiscal Year 2001. Congress directed DOE to provide up to $95 million in cost-shared funding to demonstrate commercial-scale technologies that improve the reliability and environmental performance of existing and new coal-fired power plants in the United States. Congress expected the selected technologies to provide options by which coal plants could continue to generate low-cost electricity with improved performance and in compliance with stringent environmental standards.

The PPII Solicitation, issued in February 2001, required participants (i.e., the non-federal-government participant or participants) to offer projects having potential for demonstrating substantial improvements in power plant performance, leading to enhanced electric reliability. These improvements included increased efficiency of electricity production, reduced environmental impacts, and/or increased cost-competitiveness. The projects were also required to be applicable to a large portion of existing plants and and of commercial scale in order to enhance opportunities for timely deployment.

In response to the solicitation, DOE received 24 proposals in April 2001 and selected 8 of the projects in September 2001 based on the following evaluation criteria: technical merits of the proposed technology (40%), commercial viability and market potential of the proposed technology (30%), and management approach and capabilities of the project team (30%). Along with the technical merits, DOE considered the participant's funding and financial proposal; DOE budget constraints; environmental, health and safety implications; and program policy factors. Following selection, two of the projects were withdrawn by their participants in March 2002 and in October 2002.

Each project participant is required to finance at least 50% of the total cost of the project. After completion of a successful project demonstration, the participant would be obligated to repay the government's financial contribution to ensure that taxpayers benefit from a successful project. The project participant takes primary responsibility for designing, constructing, and demonstrating the project. During project execution, the government oversees project activities, provides technical advice, assesses progress by periodically reviewing project performance with the participant, and participates in decision making at major project junctures. In this manner, the government ensures that schedules are maintained, costs are controlled, project objectives are met, and the government's funds are repaid.

DOE expects to provide approximately $51 million for the 6 remaining projects. Private sector sponsors are expected to contribute nearly $61 million, exceeding the 50% private sector cost-sharing mandated by Congress. The host sites for the projects cover a large geographical cross-section of the United States, including Florida, Virginia, New York, Ohio, South Dakota, and Kansas. The duration of the demonstration projects ranges from slightly over a year to five years.

1.2 PROPOSED ACTION

The proposed action is for DOE to provide cost-shared funding support for the design, construction, and demonstration of an integrated multi-pollutant control system at the existing 107-MW Unit 4 of AES's coal-fired Greenidge Station in Dresden, New York. DOE's share of the funding for the 4.5-year demonstration project is expected to be about $14.5 million, while about $18.3 million would be provided by CONSOL and its project partners. The commercial-scale demonstration would allow utilities to make decisions regarding the integrated emissions control system as a viable commercial option.

CONSOL Energy Inc. and AES Greenidge LLC conceived and proposed the technologies in response to the DOE solicitation. Because DOE's role would be limited to providing the cost-shared funding for the proposed project, DOE's will decide whether or not to fund the project. DOE's limited involvement constrains the range of alternatives considered in the EA (Section 2.2), and DOE will make its decision based on those alternatives.

1.3 PURPOSE

The purpose of the proposed project is to generate technical, environmental, and financial data from the design, construction, and operation of the proposed combination of technologies to allow industry to assess the project's potential for commercial application. The proposed combination of technologies is designed to reduce the capital and operating costs of environmental controls for SO_2, NO_x, SO_3, HCl, HF, Hg, and visible emissions. A demonstration indicating that the performance and cost targets are achievable at the 100-MW scale would convince potential customers in the smaller boiler market that the integration of these systems is not only feasible but economically attractive.

1.4 NEED

The need for the proposed project is to address the Congressional mandate in Public Law 106-291 to demonstrate technologies at the commercial scale that improve the reliability and environmental performance of existing and new coal-fired power plants in the United States. DOE's cost-shared funding would help reduce the financial risk to the project participant in demonstrating the proposed combination of technologies:

the single-bed selective catalytic reduction (SCR) system and the circulating dry scrubber (CDS).

The smaller boiler market is the target for the proposed combination of technologies. Currently, there are about 500 units in the United States less than 300 MW in size with a combined generating capacity of about 69,000 MW, which represents about 25% of the installed coal-based generating capacity and almost 50% of the installed boilers. The 500 units are the target market for this combination of technologies because, based on information developed from potential purchaser interviews, the smaller boilers are likely to either switch fuel or be retired in the future. If only the 190 boilers less than 110 MW are retired, the generating capacity would be reduced by up to 16,000 MW, which would exacerbate electricity and natural gas supply and distribution problems throughout the United States. Therefore, a strong incentive exists to commercialize technologies designed specifically to meet the environmental compliance needs of the smaller generating units. Because the SCR system is a low-cost option for controlling NO_x emissions from smaller generators and allows greater fuel flexibility, such as co-firing coal and biomass, it provides a feasible alternative to retiring units as NO_x allocations are reduced and the NO_x credit market tightens.

1.5 NATIONAL ENVIRONMENTAL POLICY ACT STRATEGY

This EA has been prepared in compliance with NEPA for use by DOE decision-makers in determining whether or not to provide cost-shared funding for the design, construction, and demonstration of the proposed project under the PPII solicitation. DOE's policy is to comply fully with the letter and spirit of NEPA, which ensures that early consideration is given to environmental values and factors in federal planning and decision making. No action taken by DOE with regard to any proposal, including project selection or award, is considered a final decision prior to completion of the NEPA process.

For this proposed project, DOE has determined that an EA should be prepared to assess the significance of potential impacts resulting from the proposed action and reasonable alternatives. The purpose of the EA is to provide a sufficient basis for determining whether DOE should then prepare an Environmental Impact Statement (EIS) or should issue a Finding of No Significant Impact (FONSI). Based on the findings of this EA, if DOE determines that providing cost-shared funding would constitute a major federal action because the proposed project may significantly affect the quality of the human environment, then an EIS will be prepared to assess the potential impacts in more detail. However, if DOE determines that providing cost-shared funding would not constitute a major federal action because the proposed project would not significantly affect the quality of the human environment, then DOE will issue a FONSI.

The Oak Ridge National Laboratory (ORNL) has assisted DOE in preparing this EA and supporting documents for the proposed project. In independently assessing the issues and preparing the EA, ORNL has utilized information provided by DOE; other federal, state, and local agencies; the project participant team; and others. DOE is responsible for the scope and content of the EA and supporting documents and has provided direction to ORNL, as appropriate, in the preparation of these documents.

The issues that have been identified and evaluated in the EA include land use, aesthetics, atmospheric resources, water resources, geological resources, floodplains, wetlands, ecological resources, waste management, cultural resources, socioeconomic resources, transportation, noise, electromagnetic fields, and human health and safety. Related evaluations include impacts of commercial operation, cumulative effects, regulatory compliance and permit requirements, irreversible or irretrievable commitments of resources, and the relationship between short-term uses of the environment and long-term productivity. The scope of the assessment includes upgrades and alterations to Greenidge Station that are not considered part of the proposed project (i.e., replacing the secondary superheater section, installing low-NO_x burners, and potentially replacing the economizer and primary superheater sections) because they are inseparably linked with the proposed project (i.e., the integrated multi-pollutant control system would require much of the combined equipment, which would be installed concurrently).

2. THE PROPOSED ACTION AND ALTERNATIVES

This section discusses the proposed action, the no-action alternative (including four scenarios that would reasonably be expected to result as a consequence of the no-action alternative), and alternatives dismissed from further consideration.

2.1 PROPOSED ACTION

The proposed action is for DOE to provide support through cost-shared funding for the design, construction, and demonstration of an integrated multi-pollutant control system at the existing Unit 4 of AES's coal-fired Greenidge Station in Dresden, New York (Section 1.2). The proposed action described in the following sections is DOE's preferred alternative.

2.1.1 Project Location and Background

The site for the proposed project is located at Greenidge Station, which is immediately southeast of Dresden, New York, along the western shore of Seneca Lake (Figure 2.1.1). The site is in a rural area of Torrey Township within Yates County. The nearest large town is Geneva, located about 15 miles to the north at the northern tip of Seneca Lake. Penn Yan, the county seat of Yates County, is located about 5 miles to the west of Greenidge Station.

Figure 2.1.1. Regional location map for the proposed project.

Greenidge Station, which occupies a 153-acre site (Figure 2.1.2), currently consists of the 54-MW Unit 3 and the 107-MW Unit 4, which generate a total of approximately 161 MW (net) of electricity for the power grid. An additional 8 to 9 MW are produced to satisfy internal electrical needs at the station (the difference between gross MW and net MW). Figure 2.1.3 is a photograph of Greenidge Station, as viewed toward the northwest. The plant site is bounded on the east by Seneca Lake; on the north by the Keuka Lake Outlet; on the west by Route 14; and on the south by Ferro Corporation. A mix of agricultural, industrial, commercial, and residential land use exists in the vicinity. The main entrance to the plant is easily accessed from Route 14. In addition, AES hauls fly ash for disposal at its 143-acre Lockwood Landfill, which is located on the opposite side of Route 14 to the west-southwest of Greenidge Station (Figure 2.1.2). The equipment for the proposed project would occupy about 3 acres of land, which currently serves as a paved laydown area and contractor parking lot adjacent to the existing powerhouse for Units 3 and 4 (Figure 2.1.4). The 3-acre site was previously excavated and graded in preparation for construction of a new unit, but those plans have since been abandoned.

Units 1 and 2 of Greenidge Station were constructed for the New York State Electric & Gas Corporation in 1937 and 1939, respectively. The power plant expanded in 1950 with the construction of Unit 3 to provide additional electricity needed in the area. Construction of Unit 4, the host unit for the proposed project, began in December 1951, and the unit was placed in service in December 1953. Units 1 and 2 were retired in the 1980s at the end of their useful lifetime. The boilers and turbines were removed from the powerhouse but their two idle chimneys remain adjacent to the powerhouse. Consequently, Units 3 and 4 occupy part of the powerhouse, while the remaining area formerly housing Units 1 and 2 is empty. This unoccupied space is insufficient to house the equipment for the proposed project; in particular, the circulating dry scrubber (CDS) would be taller than the inside height of the powerhouse. Boilers 1 and 2 served the Unit 1 steam turbine, Boiler 3 served the Unit 2 steam turbine, Boilers 4 and 5 serve the Unit 3 steam turbine, and Boiler 6 serves the Unit 4 steam turbine. AES bought Greenidge Station from the New York State Electric & Gas Corporation in May 1999. The plant employs 44 people.

Units 3 and 4 burn eastern bituminous pulverized coal. Conveyors with a capacity of 300 tons per hour transport crushed coal to the powerhouse for storage in the bunkers prior to combustion in the 3 remaining boilers (Boilers 4, 5, and 6). All outside conveyors are enclosed on three sides for dust control. Unit 4 also currently uses waste wood as feedstock to provide up to 10% of the heat input to the furnace (and is permitted to combust up to 30% waste wood by total weight). Units 3 and 4 use once-through cooling for non-contact condensing of the steam exhausted from the steam turbine generators. Water for cooling is drawn from Seneca Lake, and the heated water is returned to the lake via a discharge channel and Keuka Outlet. Trains and trucks deliver materials to the plant (Section 2.1.6.3).

For emissions control, neither Unit 3 nor Unit 4 is equipped with a scrubber, but Unit 3 uses two electrostatic precipitators (ESPs) for particulate control (one for each boiler), and another ESP serves Unit 4. To control NO_x emissions, Unit 3 uses overfire air (air injected above the main combustion zone in a boiler for more complete combustion). In 1994, a gas reburn system was installed on Unit 4 to provide natural gas and overfire

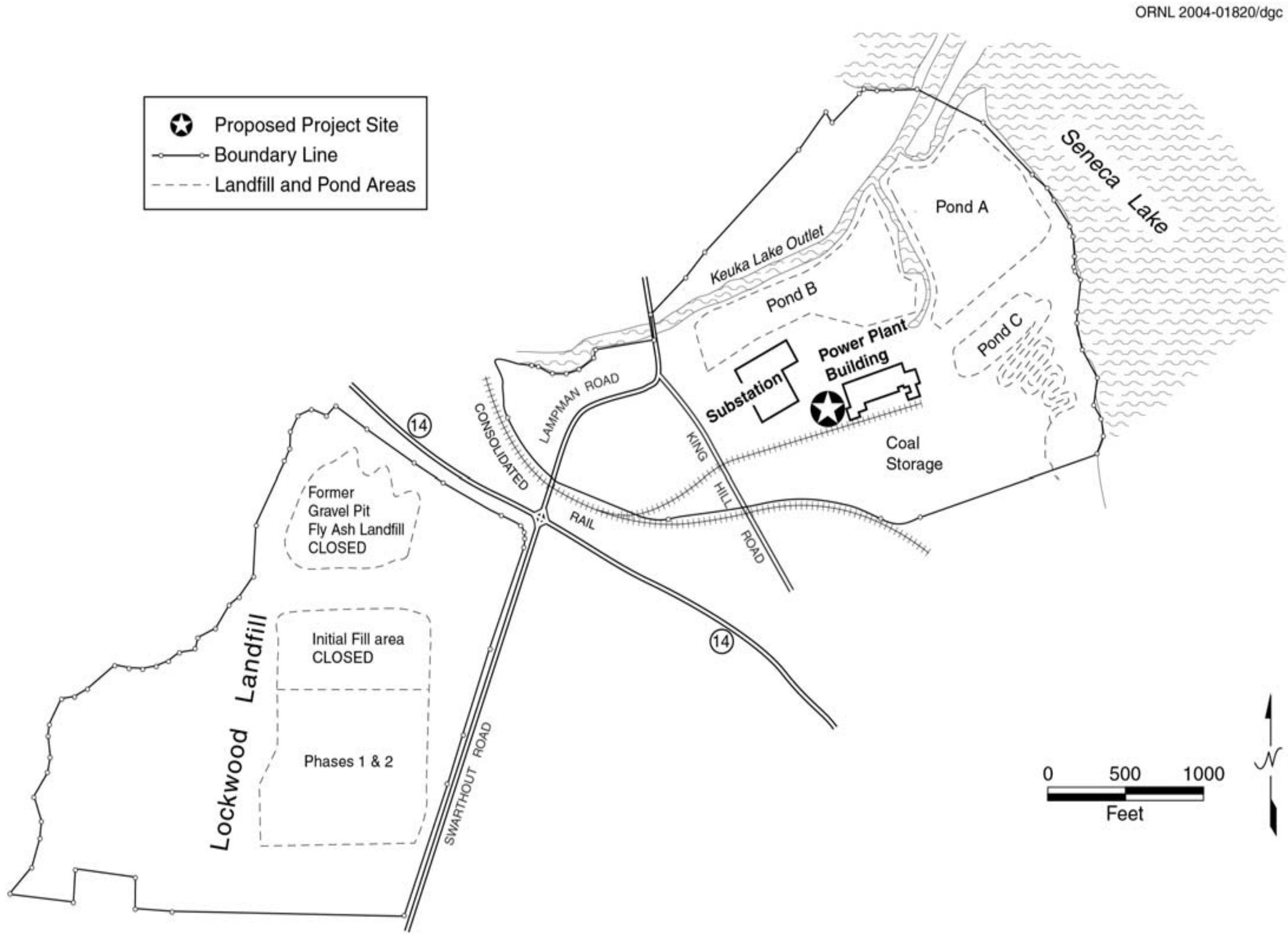

Figure 2.1.2. Site of Greenidge Station and Lockwood Landfill.

Figure 2.1.3. Photograph of Greenidge Station, as viewed toward the northwest.

Figure 2.1.4. Photograph of the site for the proposed project at Greenidge Station, as viewed toward the northwest.

air for NO_x control.[1] When the complete system was operating, combustion of natural gas in Unit 4 provided about 15% of the total heat input to the boiler. Currently, overfire air is used without natural gas because the price of natural gas is very high.

2.1.2 Technology Description

The proposed project would integrate a single-bed selective catalytic reduction (SCR) system for NO_x control and a CDS for SO_2, Hg, HCl, HF, and SO_3 control. By reducing SO_3 emissions, the CDS would also minimize visible emissions from the stack. This pollution control system is particularly suited for retrofitting smaller (<300 MW) coal-fired boilers that could be vulnerable to retirement or fuel switching under current environmental regulations.

The multi-pollutant control system is depicted in Figure 2.1.5. The NO_x control system consists of commercially available low-NO_x burners (not considered part of the proposed project because the technology is mature in the market), a single-bed SCR system in the flue gas duct, an ammonia (NH_3) storage and vaporization system, and an ammonia injection system. The CDS system consists of a hydrator and hydrated lime feed system, the CDS vessel, an ESP or baghouse for particulate control, and a carbon injection system for Hg control. The CDS is expected to reduce fine particulate emissions because it agglomerates fine particulate matter into coarser material that would be collected in an ESP or baghouse.

The in-duct SCR system is a mostly passive technology with a minimal amount of moving parts, in which NO_x reduction occurs via a chemical reaction with ammonia in the presence of a catalyst. Ammonia supply to the flue gas stream relies on an ammonia pump, control valves, and a dilution air blower. Ammonia flow is controlled by two NO_x analyzers in the flue gas. Because the technology is passive, negligible impact on station reliability is anticipated.

The CDS system uses an absorption tower that contains no moving parts. Because water containing a minimal amount of dissolved or suspended solids is sprayed into the system, feedline plugging, nozzle plugging, erosion, abrasion, and solids build-up are avoided. Because the injected water evaporates completely in the absorption tower, the process operates as a dry system. A mixture of hydrated lime and dry fly ash collected in the ESP or baghouse is injected into the absorption tower via an airslide. Gravity provides the force for injection because the bottom of the particulate control device is located higher above the ground than the injection point on the absorption tower. The initial feed rate of hydrated lime is determined by measuring the SO_2 concentration in the inlet flue gas. The feed rate is adjusted by monitoring the SO_2 concentration at the exit of the particulate control device. The gas temperature leaving the absorber controls the amount of flue gas cooling water injected through high-pressure flow nozzles into the absorber. Solids are discharged from the system at the same rate that hydrated lime, fly ash, and SO_2 enter the system.

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[1] In a gas reburn system, coal and combustion air to the main burners are reduced and natural gas is injected to create a fuel-rich secondary combustion zone above the main burner zone, with final combustion air injected to create a fuel-lean burnout zone. The formation of NO_x is inhibited in the main burner zone due to the reduced combustion intensity, and NO_x is destroyed in the fuel-rich secondary combustion zone by conversion to molecular nitrogen.

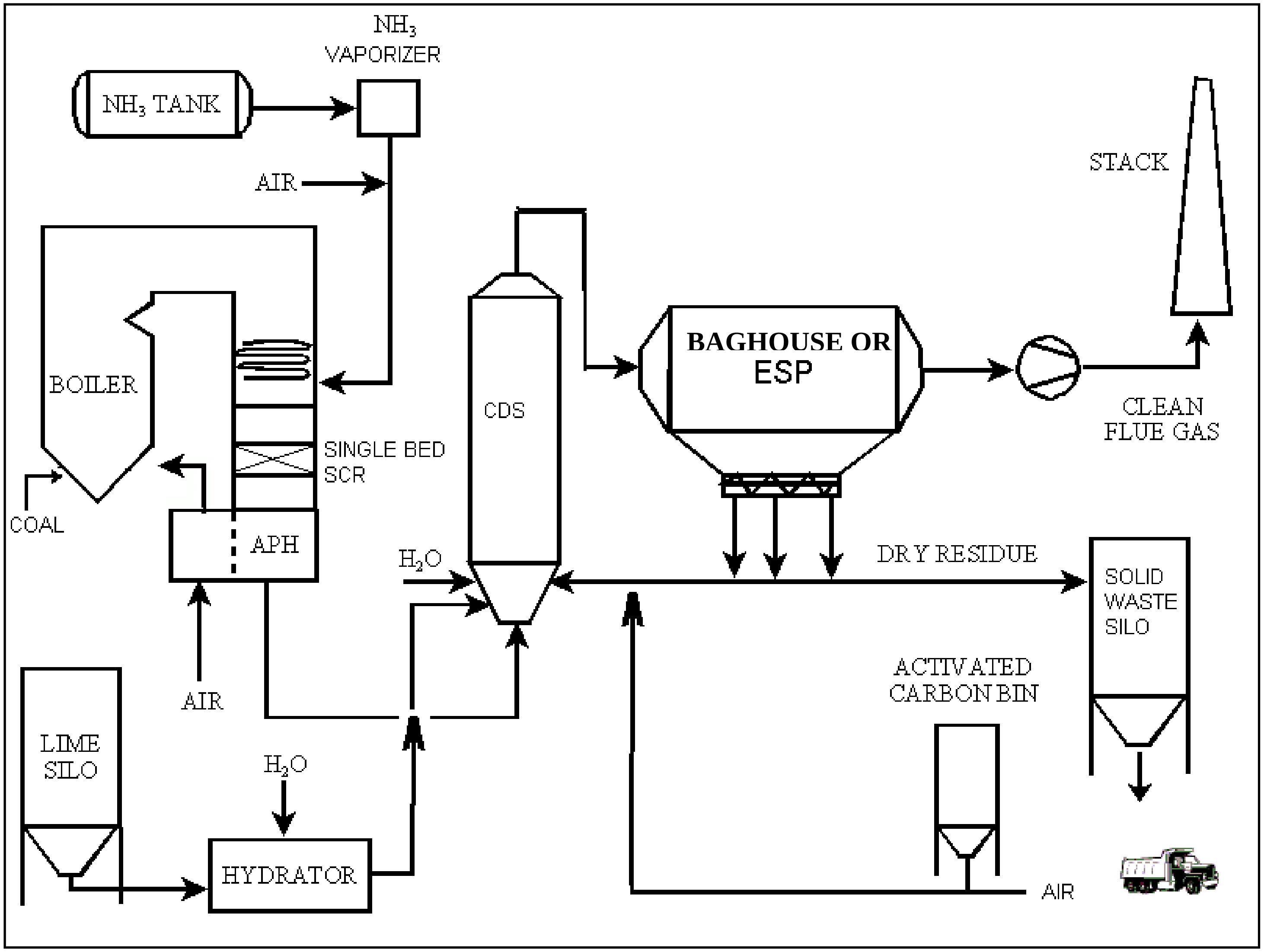


Figure 2.1.5. A generalized diagram of the proposed multi-pollutant control system.

The operating reliability of the CDS process is expected to be greater than flue gas desulfurization (FGD) processes currently in use because of its simplicity, minimal number of process components, and ease of control. In addition, because of a smaller number of components to be installed and the ability to construct the CDS system without affecting existing power plant operation, the time required to connect the system would be relatively short, which would minimize unit downtime. Another advantage of the CDS technology compared to traditional FGD systems is that it consumes less electricity. The CDS system would only require about 0.5% of unit power generation compared to an FGD process requirement for 0.7-1.5% of the generated power.

The goals of the proposed demonstration include both improved cost-competitiveness with current technologies (particularly for SO_2, NO_x, and Hg control on smaller coal-fired units) and greatly reduced Hg, SO_3, and fine particulate emissions compared to conventional technologies. The following emissions targets have been established for the integrated technologies compared with uncontrolled emissions: a 95% reduction in emissions of SO_2, SO_3, HCl, and HF, a 60% to 90% reduction in Hg emissions, NO_x emissions of less than 0.122 lb/MMBtu, and no visible emissions from the stack.

2.1.3 Project Description

The proposed project would integrate the technologies described in Section 2.1.2 into the existing 107-MW Greenidge Unit 4. Because of the additional particulate loading resulting from the injection of lime and powdered activated carbon, a new ESP or new baghouse would replace the existing ESP at Unit 4. The successful bidder providing the equipment would decide whether to install an ESP or a baghouse; however, the equipment selection is inconsequential for this analysis in this EA because the specifications for particulate control would be identical in either case. Bottom ash would continue to be sold to municipalities to provide road traction during winter driving conditions. Disposal of fly ash would continue at AES's nearby Lockwood Landfill, while commercial application of the material would be pursued (e.g., cinder blocks, stabilization agent).

Because Greenidge Unit 4 currently uses waste wood as feedstock to provide up to 10% of the heat input to the furnace (and is permitted to combust up to 30% waste wood by total weight), the proposed project would determine the effect of biomass firing on the performance of the integrated pollution control technologies. In addition, the project would quantify the magnitude of cabon dioxide ($CO_{2)}$ emissions reductions and fuel cost reductions associated with using waste wood as feedstock.

2.1.4 Construction Plans

Construction activities associated with the proposed project would include foundation laying, steel fabrication, piping installation, and electrical wiring installation. Construction would begin about April 2005 and continue until April 2006, at which time a major outage would be conducted to tie in the equipment for the proposed project to the existing Unit 4, as well as tying in some other modifications. Upgrades and alterations to Greenidge Station, which are not part of the proposed project but which are required by the integrated multi-pollutant control system or are important features in the overall renovation, include replacing the secondary superheater section, installing low-NO_x

burners, and potentially replacing the economizer and primary superheater sections. The duration of the Unit 4 outage would be about 2 months. If construction progress were insufficient to begin the outage in April 2006, the flexibility would exist to perform the outage in the fall of 2006. The timing of the Unit 4 outage would correspond with periodic maintenance outages scheduled for the spring and fall to avoid the peak load periods during the summer and winter. Startup and checkout of the integrated multi-pollutant control system would begin in June 2006 and be completed in September 2006.

About 20 to 30 construction workers would be involved with excavation and laying foundations during the initial construction at the site. Approximately 100 to 150 workers would be required during the peak construction period of tying in the equipment. Due to carpooling, about 75 construction workers' vehicles would be parked daily at the station during this peak period.

Locally obtained construction materials would include crushed stone, sand, and lumber for the proposed facilities and temporary structures such as enclosures, forms, and scaffolding. Components of the facilities would include structural steel, concrete, piping, ductwork, insulation, and electrical cable.

During construction, major components and fabricated equipment would be delivered to the site by truck. About 15 trucks would be expected to deliver materials daily for the proposed project during peak construction periods (i.e., during concrete foundation pouring). Approximately one truck per week would haul away construction debris to a municipal landfill (Section 2.1.7.3).

Land requirements during construction and operation are discussed in Section 2.1.6.1.

2.1.5 Operational Plans

Demonstration of the proposed project would be conducted within the 4.5-year period of the cooperative agreement covering September 2004 through February 2009. The actual performance testing and monitoring would occur during the 12-month period from September 2006 until September 2007. The level of staffing at Greenidge Station would remain at 44 employees during the demonstration. As with current practice, 4 plant workers would be on duty during each of four rotating 12-hour shifts, in addition to maintenance workers, managers, and administrative staff working regular hours.

If the demonstration is successful, commercial operation would follow immediately without change from the demonstration period (Section 5). The details of injection rates and control levels for the proposed project would be determined during the demonstration. Long-term staffing would not be expected to change from existing levels. The integrated multi-pollutant control system would be designed for a lifetime of 20 years.

Unit 4 would be expected to operate at generally the same power level and percentage of time as under current conditions, maintaining a combustion efficiency of about 32% and a capacity factor of about 80%. Operation of the proposed project would require about 1 MW of electricity generated by Greenidge Station. Because Units 3 and 4 are usually at their peak capacity when they're operating, the loss of 1 MW to the electrical grid would likely be offset by other power plants within the grid. However, because the amount is very small compared with regional electrical capacity, the offset would barely be perceptible and is not evaluated further.

2.1.6 Resource Requirements

Table 2.1.1 displays the operating characteristics, including resource requirements, for the existing Greenidge Station compared with the plant after implementation of the proposed project.

2.1.6.1 Land Area Requirements

A portion of the 3-acre, previously disturbed site for the proposed project would be used temporarily during construction activities for equipment/material laydown, storage, assembly of site-fabricated components, staging of material, and facilities to be used by the construction workforce (i.e., offices and sanitary facilities). Other smaller vacant, cleared areas around the site would also be used as staging and/or fabrication areas.

The permanent structures, including surrounding access space, for the proposed project would occupy a total of about 3 acres of land. Limited site clearing and grading would be required because the land currently serves as a paved laydown area and contractor parking lot adjacent to the existing powerhouse for Units 3 and 4. A new paved parking lot would likely be built on vacant, cleared land near the powerhouse to compensate for the loss of the existing lot.

2.1.6.2 Water Requirements

Water would be used during construction of the proposed project for various purposes, including personal consumption and sanitation, concrete formulation and preparation of other mixtures needed to construct the facilities, equipment washdown, general cleaning, dust suppression, and fire protection. Potable water used during construction would be supplied by the Penn Yan municipal water system, which provides water to Dresden, while service water would be drawn from the underground conduit that supplies Unit 3 cooling water and plantwide service water (i.e., water used for auxiliary equipment cooling, equipment washing, and demineralization). Combined potable and service water use during construction would average about 1 gallon per minute (gpm). Drinking water also would be provided using bottled water. Portable toilets would minimize requirements for additional sanitary water.

During demonstration of the proposed project, Greenidge Station cooling water and service water would continue to be provided by Seneca Lake, while potable water would continue to be supplied by the Penn Yan municipal water system. For part of its water needs, Greenidge Station is equipped with an 8-ft diameter gravity-fed intake pipe that extends underwater approximately 700 ft beyond the shoreline to a lake-bottom intake structure. Beneath the shoreline, the pipe feeds into an underground concrete tunnel that conveys the water to the powerhouse. At the powerhouse, most of the water is pumped for use as noncontact cooling water to condense the steam exhausted from the Unit 3 steam turbine, while the remaining water is pumped for use as service water by the entire plant. The cooling water is returned to the lake after passing through the Unit 3 condenser, while the service water undergoes treatment prior to discharge to the C pond (Figure 2.1.2). Unit 4 is equipped with a separate intake structure, intake pipeline, pump house, and discharge pipeline used exclusively for its cooling water. A 7-ft diameter intake pipe extends approximately 650 ft beyond the Seneca Lake shoreline above the lake surface, terminating in a submerged intake structure about 25 ft below the lake

Table 2.1.1. Typical operating characteristics for Greenidge Station Unit 4 alone and combined with Unit 3

Operating characteristics	Unit 4		Units 3 and 4	
	2002 base year	Including the proposed project	2002 base year	Including the proposed project
Generating capacity (net), MW	107	106	161	160
Capacity factor, %[a]	80	No change	80	No change
Size of power plant site, acres	153	No change	153	No change
Size of project site, acres		3		3
Size of nearby Lockwood Landfill, acres	143	No change	143	No change
Bituminous coal consumption, tons/year	290,000	No change	450,000	No change
Wood consumption, tons/year	11,450	No change	11,450	No change
No. 2 fuel oil consumption, gallons/year	49,000	No change	120,000	No change
Lime, tons/year	0	18,940	0	18,940
Ammonia, tons/year	0	128	0	128
Activated carbon, tons/year	0	43	0	43
Air emissions, tons/year				
Sulfur dioxide (SO_2)	13,369	602	19,450	6,683
Oxides of nitrogen (NO_x)	1,820	660	3,190	2,030
Particulate matter (PM-10)	63	63	95	95
Particulate matter (PM-2.5)	28	28	42	42
Carbon monoxide (CO)	74	74	92	92
Volatile organic compounds (VOCs)	15	15	18	18
Hydrogen chloride (HCl)	276	14	409	147
Hydrogen fluoride (HF)	33	2	50	19
Mercury (Hg)	0.012	0.005	0.018	0.011
Ammonia (NH_3)	0	0.14	0	0.14
Carbon dioxide (CO_2)	900,000	900,000[b]	1,300,000	1,300,000[b]

Table 2.1.1. concluded.

Operating characteristics	Unit 4		Units 3 and 4	
	2002 base year	Including the proposed project	2002 base year	Including the proposed project
Water use, gpm				
Noncontact cooling water	68,000	No change	93,000	No change
Service water	0	93	500	593
Potable water	1.2	No change	112	No change
Effluents, gpm				
Noncontact cooling water	68,000	No change	93,000	No change
Treated wastewater to Seneca Lake	0.7	No change	1	No change
Solid waste, tons/year				
Bottom ash	5,800	No change	8,700	No change
Fly ash	40,000	70,000	59,000	89,000

[a] Capacity factor is the ratio of the energy output during a period of time to the energy that would have been produced if the equipment had operated at its maximum power during that period.

[b] CO_2 emissions would probably not change substantially from the current level because the circulating dry scrubber (CDS) would be expected to decrease CO_2 emissions but the decrease would probably be offset by the reduced boiler thermal efficiency resulting from the new low-NO_x burners (not considered part of the proposed project).

surface. The cooling water is returned to Seneca Lake from the units' separate discharge pipelines via a common discharge channel north of the powerhouse that flows northward into Keuka Outlet, which was formerly part of the canal system. Keuka Outlet, in turn, flows eastward into Seneca Lake. The actual increase in cooling water temperature resulting from the heat transfer to condense the steam exhausted from the turbines is about 18-20°F. Figure 2.1.6 is a water flow diagram that depicts current water requirements and discharges at Greenidge Station.

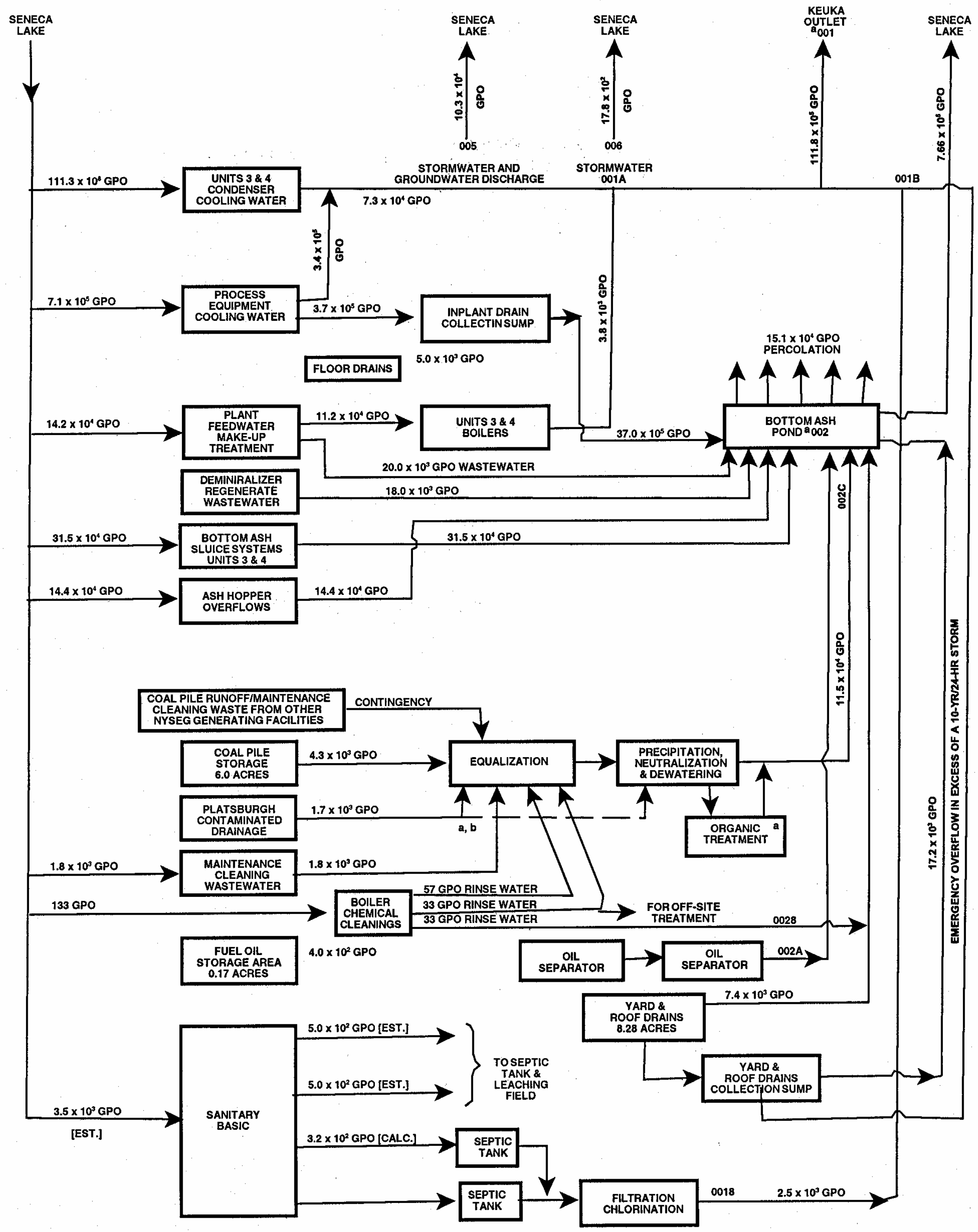
During the demonstration, the total flow of once-through, noncontact cooling water required to operate both units of the power plant at full load would continue to average 93,000 gpm. Potable water needs for the power plant would continue to be about 1.2 gpm. The plant's requirements for service water would increase from the current level of about 500 gpm to a level of 593 gpm because of the additional water needed for the lime hydrator and for the CDS. The lime hydrator would use about 7 gpm and the CDS would use approximately 86 gpm. The water would be drawn from Seneca Lake using the underground conduit that supplies Unit 3 cooling water and plantwide service water. The water would be consumed during the proposed processes rather than being returned to the lake. This additional water would represent approximately 0.1% of Greenidge Station's current water use supplied by the lake and about 15% of the plant's consumptive use.

2.1.6.3 Fuel and Sorbent Requirements

The current fuel requirements of Greenidge Station would continue at approximately the same level during the demonstration of the proposed project. The plant annually burns about 450,000 tons of eastern bituminous coal. Currently, approximately 90-93% of the coal is shipped by rail to the plant from mines near Wana, West Virginia, in Monongalia County near the southwestern corner of Pennsylvania, about 275 miles to the southwest of Greenidge Station. A train of 50 rail cars delivers coal to the station approximately twice weekly. Coal is dumped from the bottom of the rail cars into hoppers below the tracks. Occasionally, a train of 100 cars transports coal to the Dresden area, with 50 rail cars being delivered to Greenidge Station and the remaining 50 cars being held at a railroad siding immediately north of Dresden. The rail cars at the siding are switched with the rail cars at the power plant after the initial 50 cars have been unloaded.

The remaining 7-10% of the coal, about 30,000 to 35,000 tons annually, is currently delivered by truck from the Fisher Mining Company's Thomas mine near English Center, Pennsylvania, about 100 miles to the south of Greenidge Station. About 1,300 loads are delivered annually (i.e., about 25 loads per week) in 25-ton trucks, which dump the coal directly on a coal storage pile. The two coals are segregated within the storage pile and blended at the power plant to reduce the overall sulfur content of the higher-sulfur coal delivered by train using the lower-sulfur coal delivered by truck. While Fisher Mining Company currently is the only supplier of coal by truck, other small mines in the region could also supply lower-sulfur coal. Table 2.1.2 presents an analysis of the composition of the two types of coal.

During demonstration of the proposed project, the lower-sulfur coal would probably not be required for Unit 4 because the CDS would reduce SO_2 emissions from



GREENIDGE STATION WATER USE DIAGRAM -AVERAGE FLOW RATES

[a]DEPENDING ON THE TREATMENT PROCESS SELECTED, CYANIDE TREATMENT WOULD OCCUR EITHER PRIOR TO THE DETAILS TREATMENT OR IN THE ORGANIC TREATMENT PROCESS.

[b]DEPENDING ON THE TREATMENT PROCESS SELECTED, THE PLATTSBURGH CONTAMINATED DRAINAGE WOULD EITHER GO TO EQUALIZATION OR TO THE SECOND LIVE REACTOR.

Figure 2.1.6. Water flow diagram that depicts water requirements and discharges at Greenidge Station.

Table 2.1.2. Composition of bituminous coal consumed at Greenidge Station

Characteristic	Monongalia coal typical value	Fisher coal typical value
Higher heating value, Btu/lb	13,097	11,800
Analysis, % by weight		
Moisture	5.80	7.63
Carbon	72.17	67.86
Hydrogen	4.79	3.86
Nitrogen	1.36	1.55
Sulfur	2.90	0.91
Ash	7.85	13.47
Oxygen	5.04	4.72
Chlorine	0.10	0.07

unblended, higher-sulfur coal by approximately 95%. Consequently, Unit 4 would require about the same amount of coal, but about 2 additional trains of 100 rail cars each would deliver coal annually to offset about 850 loads no longer delivered by truck. Unit 3 would continue to require about 450 truck loads per year of lower-sulfur coal to blend with higher-sulfur coal at the power plant to reduce the overall sulfur content.

Unit 4 also uses waste wood as feedstock in the combustor. The waste wood currently provides up to 10% of the total heat input to the boiler, which amounts to about 11,450 tons of wood annually. The waste wood is in the form of particle board that is transported by truck from a furniture manufacturer in Jamestown, New York, about 150 miles to the west-southwest of Greenidge Station. One truck per day usually delivers the waste wood. The arrangement is mutually beneficial because the furniture manufacturer avoids the cost of landfill disposal of the waste wood, while Unit 4 uses the wood as fuel.

About 120,000 gallons (gal) of No. 2 fuel oil are consumed annually at the plant for ignition and warm-up of the units. The fuel is delivered to the plant site by tanker trucks.

During demonstration of the proposed project, annual consumption of lime for the CDS and ammonia for the SCR system would be about 18,940 tons and 128 tons, respectively. The lime would probably be delivered by truck from Bellefonte, Pennsylvania, about 170 miles to the south-southwest of Greenidge Station. About 1,000 loads would be delivered annually in 20-ton trucks. The lime could possibly be shipped by rail rather than truck. Ammonia would probably be delivered by truck from Allentown, Pennsylvania, about 200 miles to the south-southeast of the power plant. About 6 loads would be delivered annually in 20-ton tanker trucks. Annual consumption of powdered activated carbon for Hg control would be approximately 43 tons. About 3 loads would be delivered annually in 20-ton trucks. A supplier of the carbon has not yet been identified.

2.1.7 Outputs, Discharges, and Wastes

Table 2.1.1 includes a summary of discharges and wastes for the existing Greenidge Station compared with the plant after implementation of the proposed project.

2.1.7.1 Air Emissions

Air emissions from Greenidge Station would generally decrease or continue at the same level during the demonstration of the proposed project. SO_2 emissions would decrease from 19,450 tons per year currently to 6,683 tons per year. NO_x emissions would decrease from 3,190 tons per year currently to 2,030 tons per year. Because of the additional particulate loading resulting from the injection of lime and powdered activated carbon, a new, more efficient ESP or new baghouse would replace the existing ESP at Unit 4. Consequently, plantwide PM-10 and PM-2.5 emissions would probably decrease compared with current annual emissions of 95 and 42 tons, respectively. However, it is assumed in this analysis that particulate emissions would continue at the same level because the additional particulate loading would at least partially offset (1) the improved efficiency of the ESP or baghouse and (2) the probably discontinuation of Unit 4's use of higher-ash coal from the Fisher Mining Company (Table 2.1.2). CO and volatile organic compound (VOC) emissions would also be expected to remain at the same level (i.e., 92 and 18 tons per year, respectively). Plantwide Hg emissions would decrease from about 36 lb per year currently to about 22 lb per year because of the powdered activated carbon injected into the recycle stream or into the CDS. Due to ammonia (NH_3) injection into the flue gas, NH_3 emissions would increase from near zero to about 280 lb per year. Plantwide HCl and HF emissions would decrease to about 147 and 19 tons per year, respectively, compared with current emissions of 409 and 50 tons per year, respectively.

SO_3 emissions are expected to decrease by the same percentage as SO_2 emissions, but current and future emissions are not known. Trace emissions of other pollutants would include beryllium, sulfuric acid mist, benzene, arsenic, and various heavy metals. CO_2 emissions would probably not change substantially from the current level of 1,300,000 tons per year because the CDS would be expected to decrease CO_2 emissions but the decrease would probably be offset by an increase due to a change in combustion characteristics associated with the new low-NOx burners (not part of the proposed project). Although CO_2 is not considered an air pollutant, CO_2 emissions contribute to the greenhouse effect that is suspected to cause global warming and climate change (Mitchell 1989).

As discussed in Section 2.1.6.3, Unit 4 has the capability of co-firing coal with waste wood in the form of particle board, which is bonded with urea-formaldehyde. The wood contains less than 0.1% (by weight) formaldehyde, which is suspected of carcinogenic potential in humans. Emissions of organic compounds, including formaldehyde, are typically very low in power plant boilers because nearly complete combustion is attained by the high combustion temperatures and relatively long fuel-residence times. A formaldehyde emission analysis was performed by stack sampling at another New York power plant that co-fires coal with waste wood containing urea-formaldehyde (Lindsey 2004). As part of the analysis, the study included blanks to measure the ambient levels of formaldehyde in reagent solutions prior to the introduction of material collected from stack sampling. A statistical review of the data collected during the study concluded that formaldehyde levels during co-firing operation were indistinguishable from the laboratory blank levels. Also, formaldehyde emissions from

100% coal-fired operation were indistinguishable from emissions during co-firing operation, both of which were nearly undetectable (Lindsey 2004). During the demonstration of the proposed project, formaldehyde emissions would be expected to remain very low.

2.1.7.2 Liquid Discharges

The proposed project would not affect liquid effluent at Greenidge Station. The discharge of once-through, noncontact cooling water with both units operating at full load would continue to average 93,000 gpm. The cooling water from the units is discharged from separate pipelines to Seneca Lake via a common discharge channel and Keuka Outlet (Section 2.1.6.2). About 1 gpm of backwash effluent from the reverse osmosis system would continue to be discharged to C Pond (a settling pond) and ultimately to Seneca Lake. Floor drains and other collection sumps collect water potentially co-mingled with oil. Oil is captured by oil-adsorbent cloth on the surface of the sumps and the water is discharged to C Pond. The oil-adsorbent cloth is replaced periodically and transported from the site by a licensed waste management contractor to authorized facilities for disposal.

Stormwater runoff from the lined coal pile storage area is collected in the surge basin, conveyed periodically to the wastewater plant for treatment, and discharged to C Pond. Stormwater runoff from the lined Lockwood Landfill is captured using an underground leachate collection system that conveys the water to an adjacent sedimentation pond where it is sampled and treated, if necessary.

2.1.7.3 Solid Wastes

Non-hazardous solid wastes generated at Greenidge Station include used office materials, empty material containers, and coal combustion ash. Non-hazardous solid wastes, with the exception of coal combustion ash, are removed from the site at regular intervals by a waste management contractor and transported for disposal at the Ontario County municipal landfill in Flint, New York, about 15 miles to the north-northwest of Greenidge Station, or at the Seneca Meadows municipal landfill in Seneca Falls, New York, about 20 miles to the northeast of the station. As part of the proposed project, the existing Unit 4 ESP may be dismantled and the metal plating sold for scrap. The remaining material from the ESP would go to a municipal landfill.

The power plant currently generates about 8,700 tons per year of bottom ash and 59,000 tons per year of fly ash (the latter amount includes water used to wet the ash for transport). During the demonstration of the proposed project, the amount of bottom ash produced would not change, while the quantity of fly ash collected would increase to a yearly maximum of 89,000 tons due to the addition of Unit 4’s new, more efficient ESP or new baghouse, which would capture additional fly ash resulting from the injection of lime and powdered activated carbon.

Currently, all bottom ash is sold to municipalities to apply on roads for vehicle traction during treacherous winter conditions. Until sold, the bottom ash is stored in a settling pond and excavated as needed. Although some fly ash was sold until about 1995, all fly ash is currently trucked to the nearby AES-owned, double-lined Lockwood Landfill (Figure 2.1.2) for disposal. On average, 6 truck loads are transported daily from the fly ash silo to the landfill. Capacity at the landfill is sufficient for a remaining lifetime of more than 20 years. During the demonstration, bottom ash would continue to be sold to municipalities, and fly ash would be trucked to Lockwood Landfill. In addition, a commercial application for the fly ash would be pursued (e.g., cinder blocks, stabilization agent). If successfully implemented in the marketplace, the commercial application would reduce the amount of fly ash requiring disposal at the landfill to less than 89,000 tons per year.

Fly ash transported to the landfill is conditioned with water to control dust and allow compaction. Ash is transported to the landfill site in covered trucks. Most of the short haul road is on AES property. The working face at the landfill is oriented in a direction to minimize fugitive dust.

2.1.7.4 Toxic and Hazardous Materials

During operation, Greenidge Station requires potentially toxic or hazardous materials, such as chlorine and solvents, and generates potentially toxic or hazardous materials, including waste paints, oils, used rags, and empty material containers. All chemicals are properly labeled and stored according to local fire codes and Occupational Safety and Health Administration (OSHA) requirements. Chlorine is used for water filtration, while the solvents are used primarily in maintenance activities. Hazardous wastes generated during operation are removed from the site at regular intervals by a licensed waste management contractor and transported to authorized facilities for disposal. All toxic and hazardous materials are transported by truck to and from the station.

The power plant has in place a program to reduce, reuse, and recycle materials to the extent practicable. All light bulbs are treated as hazardous waste and disposed of in properly licensed facilities. The plant has a Spill Prevention, Control, and Countermeasures Plan (SPCCP) (40 CFR Part 112) that addresses the accidental release of materials to the environment.

With the exception of ammonia used in the SCR process, the proposed project would not affect the power plant's requirements for or generation of toxic and hazardous materials. Proper precautions would be taken during ammonia storage and handling to minimize the risk of an accidental release of ammonia. The ammonia would be stored in a cylindrical tank with secondary containment of sufficient volume to hold the entire contents of the tank in the unlikely event of a rupture. A SPCCP would be developed for ammonia, and the ammonia storage would comply with Emergency Planning and Community Right-to-Know Act (EPCRA) notification requirements. The ammonia would be transported by truck to the station (Section 2.1.6.3).

2.2 ALTERNATIVES

The goals of a federal action establish the limits of its reasonable alternatives under the NEPA process. Congress established the PPII with a specific goal— to demonstrate commercial-scale technologies that improve the reliability and environmental performance of existing and new coal-fired power plants in the United States. DOE’s purpose in considering the proposed action (to provide cost-shared funding) is to demonstrate the viability of the integrated multi-pollutant control system in achieving the goal for the program. Reasonable alternatives to this proposed action must be capable of meeting this purpose.

Congress also directed DOE to pursue the goals of the legislation by providing partial funding for projects owned and controlled by nonfederal-government participants. This statutory requirement places DOE in a much more limited role than if the federal government were the owner and operator of the project. In the latter situation, DOE would ordinarily be required to review a wide variety of reasonable alternatives to the proposed action. However, in dealing with a nonfederal applicant, the scope of alternatives is necessarily more restricted. It is appropriate in such cases for DOE to give substantial weight to the needs of the proposer in establishing reasonable alternatives to the proposed action. Moreover, under the PPII, DOE's role is limited to approving or disapproving the project as proposed by the participant.

Thus, the only reasonable alternative to the proposed action is the no-action alternative, including four scenarios reasonably expected as a consequence of the no-action alternative (Section 2.2.1).

2.2.1 No-Action Alternative

Under the no-action alternative, DOE would not provide cost-shared funding to demonstrate the integrated multi-pollutant control system. Without DOE participation, the proposed project would be canceled, and the proposed combination of technologies would probably not be demonstrated elsewhere. Consequently, commercialization of the integrated multi-pollutant control system could be delayed or might not occur because utilities and industries tend to use known and demonstrated technologies over new, unproven technologies. At the site of the proposed project, four reasonably foreseeable scenarios could result. None of these scenarios would contribute to the PPII goal of demonstrating technologies at the commercial scale that improve the reliability and environmental performance of existing and new coal-fired power plants in the United States.

First, AES could shut down Greenidge Station. Because the plant is expected to be subject to more stringent emissions standards, mothballing or dismantling the plant would be one option available to the owners rather than installing expensive, commercially available emissions control equipment to comply with upcoming standards. Under this scenario, no construction activities would be undertaken, and no employment would be provided for construction workers in the area except for some limited activity associated with mothballing or dismantling the plant. Existing operations would cease, no electricity would be generated at the Greenidge site, and power plant workers would lose their jobs. Resource requirements and discharges and wastes would also cease. Current environmental conditions at the site would tend to revert back to conditions prior to plant operation, and existing impacts would be reduced.

However, to meet the existing regional demand for electricity, more electricity would need to be generated at one or more other sites to offset the elimination of electrical generation at Greenidge Station. While the exact location or locations are uncertain, the sites are likely to be at existing under-utilized power plants that have excess available capacity because they are costly and inefficient to operate. This rationale is based on the premise that, to meet demand, electric utilities typically dispatch electricity according to operating cost, starting with the least costly. The under-utilized plants would also tend to be older and generate greater quantities of air emissions, liquid discharges, and solid wastes. Therefore, while current environmental impacts would be reduced at the Greenidge site, impacts would likely increase at the site(s) where electrical generation would increase to compensate for shutting down Greenidge Station.

Second, AES could install commercially available pollution controls to comply with future emissions standards. Under this scenario, operations would remain essentially the same as for the existing plant. Electricity would be generated at approximately the same rate. Resource requirements and discharges and wastes would generally be the same, except that air emissions would be reduced because of the enhanced pollution controls and solid wastes would likely increase due to the captured air emissions. Additional solid wastes would likely be recycled or sold as a usable product. Because this scenario and the proposed project involve the installation of new pollution controls on an existing unit, construction activities associated with this scenario would be similar in scale to those of the proposed project. With the exception of improving air quality, there would be minimal change in current environmental conditions at the site and the impacts would remain very similar to existing conditions.

Third, AES could switch to using natural gas rather than coal at Greenidge Station, while maintaining most of the current equipment such as the boilers, turbines, ductwork, and chimneys. The need for some of the existing infrastructure such as the coal handling facilities and ash silos would be reduced or eliminated, depending on whether Unit 4 alone or both units were switched. Because a new 14-mile natural gas pipeline would need to be constructed to deliver the fuel, construction activities would probably be at a slightly greater level than those associated with the proposed project. Because of pipeline construction, disturbance beyond the Greenidge site would be greater under this scenario. Electricity would be generated at approximately the same rate. Resource requirements and discharges and wastes would generally be smaller because of the type of fuel and because the converted facility would be more efficient than the existing plant due to a new gas-fired delivery system and other upgrades. Air emissions, particularly SO_2 emissions, would be considerably less because a new gas-fired delivery system would burn more efficiently and cleanly than an aging coal-fired power plant with limited emissions controls. Ash generation would be reduced or eliminated at the power plant, depending on whether Unit 4 alone or both units were switched. Current environmental conditions and impacts at the site would be expected to improve.

Finally, AES could purchase emissions allowances (e.g., SO_2, NO_x) as a compliance strategy for future emissions standards. By purchasing emissions allowances, AES would be compensating another utility or utilities for overcomplying with the standards while allowing the region as a whole to meet the limits for those emissions. Under this scenario, the existing power plant would continue to operate without change. No construction activities would be undertaken, and existing operations would remain essentially the same. Electricity would be generated at the same rate. Resource requirements and discharges and wastes would be the same. There would be negligible change in current environmental conditions at the site and the impacts would remain very similar to existing impacts. This scenario would not provide employment for construction workers in the area.

2.2.2 Alternatives Dismissed from Further Consideration

The following sections discuss alternatives that were initially identified and considered by the project participant. Because DOE's role is limited to providing the cost-shared funding for the selected project, DOE is limited to either accepting or rejecting the project as proposed by the participant, including the proposed technology and site. As such, reasonable alternatives to the proposed project are narrowed and the following alternatives have been dismissed from further consideration.

2.2.2.1 Alternative Sites

CONSOL Energy initially considered additional sites during their site selection process. Site selection was governed primarily by benefits that could be realized by the companies participating in the project. An existing plant site was preferred because the cost associated with construction of the project and a new power plant at an undeveloped site would be much higher and the environmental impacts likely would be much greater than at an existing facility. The site selected for the project had to provide the maximum benefit to the companies by closely meeting the project's technical needs and integrating with existing infrastructure. No other sites were considered after AES's Greenidge Station in Dresden, New York, was identified as a candidate to host the project. Based on the above considerations, other sites are not reasonable alternatives and are not evaluated in this EA.

2.2.2.2 Alternative Technologies

Other technologies have been dismissed as not reasonable. The proposed project was selected to demonstrate the operation of an integrated multi-pollutant control system on a coal-fired power plant. Other PPII projects were selected to demonstrate other coal-based technologies. The preselection reviews included environmental comparisons of proposals. The projects selected for demonstration are not considered alternatives to each other.

The use of other technologies and approaches which are not applicable to coal (e.g., natural gas, wind power, solar energy, and conservation) would not contribute to the PPII goal of demonstrating technologies at the commercial scale that improve the reliability and environmental performance of existing and new coal-fired power plants in the United States.

2.2.2.3 Other Alternatives

Other alternatives, such as delaying or reducing the size of the proposed project, have been dismissed as not reasonable. Delaying the project would not result in any change of environmental impacts once the project were implemented but would adversely delay reductions in air emissions from the existing power plant and adversely affect the PPII goal of demonstrating technologies at the commercial scale for potential customers in the smaller boiler market. The design size for the proposed combination of technologies was selected because it is considered to be typical of the smaller boiler market; the size is large enough to show utilities that the technology, once demonstrated at this scale, could be applied without further scale-up to many units of similar size. A demonstration indicating that the performance and cost targets are achievable at the 100-MW scale would convince potential customers that the integration of these systems is not only feasible but economically attractive (Section 1.3).